

SELECTED CONSOLIDATED DATA

(dollars in thousands, except per share amounts)

2000 1999 1998 1997 1996

	2000	1999	1998	1997	1996
OPERATING RESULTS					
Operating revenues					
Electric	\$ 3,531,810	\$ 2,293,184	\$ 2,006,398	\$ 1,878,553	\$ 1,718,272
Real estate	158,365	130,169	124,188	116,473	99,488
Income from continuing operations	\$ 302,332	\$ 269,772	\$ 242,892	\$ 235,856	\$ 211,059(a)
Discontinued operations	—	38,000(d)	—	—	(9,539)(b)
Extraordinary charge – net of income tax	—	(139,885)(e)	—	—	(20,340)(c)
Net income	\$ 302,332	\$ 167,887	\$ 242,892	\$ 235,856	\$ 181,180
COMMON STOCK DATA					
Book value per share – year-end	\$ 28.09	\$ 26.00	\$ 25.50	\$ 23.90	\$ 22.51
Earnings (loss) per average common share outstanding					
Continuing operations – basic	\$ 3.57	\$ 3.18	\$ 2.87	\$ 2.76	\$ 2.41(a)
Discontinued operations	—	0.45	—	—	(0.11)
Extraordinary charge	—	(1.65)	—	—	(0.23)
Net income – basic	\$ 3.57	\$ 1.98	\$ 2.87	\$ 2.76	\$ 2.07
Continuing operations – diluted	\$ 3.56	\$ 3.17	\$ 2.85	\$ 2.74	\$ 2.40(a)
Net income – diluted	\$ 3.56	\$ 1.97	\$ 2.85	\$ 2.74	\$ 2.06
Dividends declared per share	\$ 1.425	\$ 1.325	\$ 1.225	\$ 1.125	\$ 1.025
Indicated annual dividend rate – year-end	\$ 1.50	\$ 1.40	\$ 1.30	\$ 1.20	\$ 1.10
Average common shares outstanding – basic	84,732,544	84,717,135	84,774,218	85,502,909	87,441,515
Average common shares outstanding – diluted	84,935,282	85,008,527	85,345,946	86,022,709	88,021,920
TOTAL ASSETS	\$ 7,149,151	\$ 6,608,506	\$ 6,824,546	\$ 6,850,417	\$ 6,989,289
LIABILITIES AND EQUITY					
Long-term debt less current maturities	\$ 1,955,083	\$ 2,206,052	\$ 2,048,961	\$ 2,244,248	\$ 2,372,113
Other liabilities	2,811,354	2,196,721	2,516,993	2,407,572	2,428,180
Minority interests	4,766,437	4,402,773	4,565,954	4,651,820	4,800,293
Non-redeemable preferred stock of APS	—	—	85,840	142,051	165,673
Redeemable preferred stock of APS	—	—	9,401	29,110	53,000
Common stock equity	2,382,714	2,205,733	2,163,351	2,027,436	1,970,323
Total liabilities and equity	\$ 7,149,151	\$ 6,608,506	\$ 6,824,546	\$ 6,850,417	\$ 6,989,289

(a) Includes an after-tax charge of \$18.9 million (\$0.22 per share) for a voluntary severance program and about \$12 million (\$0.13 per share) of income tax benefits related to capital loss carryforwards.

(b) Charges, net of tax, associated with the settlement of a legal matter related to MeraBank, A Federal Savings Bank.

(c) Charges associated with the repayment or refinancing of the parent company's high-coupon debt.

(d) Tax benefit stemming from the resolution of income tax matters related to MeraBank, A Federal Savings Bank.

(e) Charges associated with a regulatory disallowance.

(dollars in thousands, except per share amounts) *2000* *1999* *1998* *1997* *1996*

ELECTRIC OPERATING REVENUES					
Residential	\$ 880,468	\$ 805,173	\$ 766,378	\$ 746,937	\$ 721,877
Commercial	771,909	733,038	699,016	687,988	678,130
Industrial	146,088	159,329	172,296	164,696	162,324
Irrigation	6,498	7,374	7,288	8,706	9,448
Other	10,719	11,708	10,644	11,842	13,078
Total retail	1,815,682	1,716,622	1,655,622	1,620,169	1,584,857
Wholesale	1,594,541	506,877	300,698	226,828	98,560
Transmission for others	14,766	11,348	11,058	10,295	10,240
Miscellaneous services	106,821	58,337	39,020	21,261	24,615
Total electric operating revenues	\$ 3,531,810	\$ 2,293,184	\$ 2,006,398	\$ 1,878,553	\$ 1,718,272
ELECTRIC SALES (MWh)					
Residential	9,780,680	8,774,822	8,310,689	7,970,309	7,541,440
Commercial	10,057,707	9,543,853	8,697,397	8,524,882	8,233,762
Industrial	2,511,292	2,561,349	3,279,430	3,123,283	3,039,357
Irrigation	87,073	99,669	84,640	112,363	121,775
Other	97,772	94,877	90,927	86,090	84,362
Total retail	22,534,524	21,074,570	20,463,083	19,816,927	19,020,696
Wholesale	21,997,357	15,693,834	10,317,391	9,233,573	3,367,234
Total electric sales	44,531,881	36,768,404	30,780,474	29,050,500	22,387,930
ELECTRIC CUSTOMERS - END OF YEAR					
Residential	762,574	735,359	708,215	680,478	654,602
Commercial	90,273	86,707	83,506	81,246	78,178
Industrial	3,286	3,183	3,084	3,192	3,055
Irrigation	371	754	710	764	841
Other	965	932	895	851	828
Total retail	857,469	826,935	796,410	766,531	737,504
Wholesale	67	73	67	50	48
Total electric customers	857,536	827,008	796,477	766,581	737,552

See "Financial Review" on pages 20-29 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS STOCK SYMBOL: PNW

<i>2000</i>	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE	<i>1999</i>	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE(a)
2nd Quarter	35.88	27.88	33.88	0.350	2nd Quarter	42.94	36.25	40.25	0.650
3rd Quarter	51.31	33.81	50.89	0.350	3rd Quarter	41.31	34.69	36.38	—
4th Quarter	52.22	40.89	47.63	0.375	4th Quarter	38.13	30.19	30.56	0.350

(a) Dividends for the 3rd quarter of 1999 were declared in June 1999.

FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: Arizona Public Service Company (APS), Pinnacle West Energy Corporation (Pinnacle West Energy), APS Energy Services Company, Inc. (APS Energy Services), SunCor Development Company (SunCor), and El Dorado Investment Company (El Dorado) including:

- the changes in our earnings from 1999 to 2000 and from 1998 to 1999;
- the effects of regulatory agreements on our results and outlook;
- our capital needs and resources;
- major factors that affect our financial outlook; and
- our management of market risks.

OVERVIEW OF OUR BUSINESS

Pinnacle West owns all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;
- APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;
- SunCor, which is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which is primarily a venture capital and investment firm.

OUR BUSINESS STRATEGIES

Our business strategies are linked to the strong growth characteristics of Arizona and the western regional market. We are committed to the West and are pursuing the following primary strategies:

- Continuing focus on customer value provided by APS, our regulated "energy delivery" company;
- Expanding our interests in competitively efficient generation assets in the West through Pinnacle West Energy by developing new plants, increasing our ownership share of plants that we already operate and partially own, and buying plants from other utilities;
- Aggressively managing costs, with an emphasis on the reduction of variable costs per generating unit (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; and

- Managing energy activities, including:
 - continuing expansion of wholesale operations;
 - managing commodity price risk; and
 - providing sufficient capacity, energy, and ancillary services to reliability meet obligations to our regulated service customers.

BUSINESS SEGMENTS

As we discuss below in greater detail, APS' 1999 Settlement Agreement with the Arizona Corporation Commission (ACC) authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. We have internally organized our operations into the following two principal business segments, determined by products, services, and regulatory environment:

- The electricity delivery business segment, which consists of the transmission and distribution of electricity and wholesale activities; and
- The generation business segment, which consists of our generation activities.

See "Business Segments" in Note 18 for more information about our business segments. In general, we have structured our discussion below based on existing legal entities rather than the operating segments defined by the new organizational structure because we continue to analyze these matters internally by legal entity. The "Results of Operations," for example, primarily reflect the results of APS' operations because APS currently owns substantially all of our assets and produces substantially all of our profits.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 35. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

The following is a summary of net income for 2000, 1999, and 1998:

(dollars in millions)	<i>2000</i>	<i>1999</i>	<i>1998</i>
APS	\$ 307	\$ 267	\$ 246
Pinnacle West Energy	(2)	—	—
APS Energy Services	(13)	(9)	—
SunCor	11	6	45
El Dorado	2	11	5
Parent Company	(3)	(5)	(53)
Income from Continuing Operations	302	270	243
Income Tax Benefit from Discontinued Operations	—	38	—
Extraordinary Charge – Net of Income Taxes of \$94	—	(140)	—
Net Income	\$ 302	\$ 168	\$ 243

2000 Compared with 1999

Our 2000 consolidated net income was \$302 million compared with \$168 million in 1999. Our 2000 net income increased \$134 million over 1999 primarily because of a \$140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting increase in our 2000 net income was partially offset by a \$38 million income tax benefit from discontinued operations that we also recorded in 1999. See “Regulatory Agreements” below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased \$32 million, or 12%, over 1999 primarily because of increases in wholesale and retail electric sales and in real estate profits. These positive factors more than offset decreases resulting from the completion of investment tax credit (ITC) amortization in 1999, reductions in retail electricity prices, lower earnings from El Dorado, and miscellaneous factors. See “Regulatory Agreements” below and Note 3 for information on the price reductions. See “Regulatory Agreements” below and Note 4 for additional information about ITC amortization.

In 2000, electric operating revenues increased \$1.2 billion primarily because of:

- increased wholesale revenues (\$1.1 billion);
- increases in the number of retail electricity customers and the average amount of electricity used by customers (\$97 million); and
- weather impacts (\$33 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail electricity prices (\$28 million).

The increase in wholesale revenues resulted primarily from higher prices and increased activity in western United States wholesale power markets. These revenues were accompanied by increases in purchased power and fuel expense of \$1.0 billion.

Fuel and purchased power expenses were also higher because of higher retail sales volumes and increased prices.

The increase in real estate profits resulted from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses, which primarily related to customer growth, was substantially offset by \$20 million of non-recurring items recorded in 1999.

Net other income and expense decreased \$11 million primarily because of a decrease in the market value of El Dorado’s investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado’s investments.

1999 Compared with 1998

Our 1999 consolidated net income was \$168 million compared with \$243 million in 1998. Our 1999 net income decreased \$75 million from 1998 primarily because of a \$140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting decrease in our 1999 net income was partially offset by a \$38 million income tax benefit from discontinued operations that we also recorded in 1999. See “Regulatory Agreements” below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased \$27 million, or 11%, over 1998 primarily because of increases in retail electricity revenues and lower financing costs. These positive factors more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See “Regulatory Agreements” below and Note 3 for additional information about the price reductions.

In 1999, electric operating revenues increased \$287 million primarily because of:

- increased wholesale revenues (\$219 million);
- increases in retail electricity customers and the average amount of electricity used by customers (\$81 million); and
- miscellaneous factors (\$9 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail prices (\$22 million).

The increase in wholesale revenues resulted from higher prices and increased activity in western United States wholesale markets. The revenues were accompanied by an increase in purchased power expenses. Although these activities contributed positively to earnings in both periods, the contribution in 1999 was lower than in 1998.

Operations and maintenance expenses increased \$27 million primarily because of \$20 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were partially offset by lower employee benefit costs.

Net other income and expense increased \$10 million primarily because of an increase in the market value of El Dorado’s

investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

Regulatory Agreements

Regulatory agreements approved by the ACC affect the results of APS' operations. The following discussion focuses on three agreements approved by the ACC, each of which included retail electricity price reductions:

- The 1999 Settlement Agreement to implement retail electric competition;
- A 1996 agreement that accelerated the amortization of APS' regulatory assets; and
- A 1994 settlement that accelerated the amortization of APS' deferred ITCs.

1999 Settlement Agreement

As part of the 1999 Settlement Agreement, APS agreed to reduce retail electricity prices for standard, full offer service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately \$24 million (\$14 million after income taxes) included the July 1, 1999 retail price decrease required by the 1996 regulatory agreement (see below). For customers having loads three megawatts or greater, standard offer rates will be reduced in annual increments that total 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, \$234 million before income taxes (\$183 million net present value) from ongoing regulatory cash flows. APS recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a \$140 million after-tax extraordinary charge on the 1999 income statement.

Under the 1996 Regulatory Agreement, APS was recovering substantially all of its regulatory assets through accelerated amortization over an eight-year period that would have ended June 30, 2004. For more details, see Note 1. The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

1999	2000	2001	2002	2003	1/1-6/30 2004	Total
\$164	\$158	\$145	\$115	\$86	\$18	\$686

See Note 3 and "Business Outlook – Electric Competition (Retail)" below for additional information regarding the 1999 Settlement Agreement.

1996 Regulatory Agreement

As part of the 1996 regulatory agreement, APS reduced its retail electricity prices by 3.4% effective July 1, 1996. This reduction decreased annual revenue by about \$49 million annually (\$29 million after income taxes). APS also agreed to

share future cost savings with its customers during the term of this agreement, which resulted in the following additional retail price reductions:

- \$18 million annually (\$11 million after income taxes), or 1.2%, effective July 1, 1997;
- \$17 million annually (\$10 million after income taxes), or 1.1%, effective July 1, 1998; and
- \$11 million annually (\$7 million after income taxes), or 0.7%, effective July 1, 1999 (as noted above, this reduction was included in the July 1, 1999 price reduction under the 1999 Settlement Agreement).

1994 Rate Settlement

As part of a 1994 rate settlement, APS accelerated amortization of substantially all of its ITCs over a five-year period that ended on December 31, 1999. The amortization of ITCs decreased annual consolidated income tax expense by about \$24 million. Beginning in 2000, no further benefits were reflected in income tax expense related to the acceleration of the ITCs (see Note 4).

CAPITAL NEEDS AND RESOURCES

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the period ended December 31, 2000 and estimated capital expenditures for the next three years:

	(actual)		(estimated)	
(dollars in millions)	2000	2001	2002	2003
APS				
Delivery	\$ 285	\$ 337	\$ 293	\$ 294
Existing Generation (a)	187	118	108	—
	472	455	401	294
Pinnacle West Energy (b)				
Generation Expansion	193	659	129	132
Existing Generation (a)	—	—	—	122
	193	659	129	254
SunCor (c)	50	75	23	14
Other (d)	—	21	9	9
Total	\$ 715	\$1,210	\$ 562	\$ 571

(a) Pursuant to the 1999 Settlement Agreement, APS is required to move its generating assets and competitive services no later than December 31, 2002.

(b) Does not include the Southern California Edison (SCE) purchase agreements. See Note 12 and "Capital Resources and Cash Requirements – Pinnacle West Energy" below.

(c) Consists primarily of capital expenditures for land development and retail and office building construction.

(d) Primarily APS Energy Services.

Capital Resources and Cash Requirements

Pinnacle West (Parent Company)

During the past three years, our primary cash needs were for:

- dividends to our shareholders;
- equity infusions into our subsidiaries, including \$200 million invested in APS from 1996 through 1999 as part of the 1996 regulatory agreement (see Note 3) and \$193 million invested in Pinnacle West Energy for 2000 capital expenditures;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

Over the next three years, we anticipate that our cash needs will fall into these same categories, although we expect our equity infusions into Pinnacle West Energy to continue as it invests in additional generating facilities (see below) until it begins to finance its own construction needs.

Our primary sources of cash are dividends from our subsidiaries and external financing. For the years 1998 through 2000, total dividends from subsidiaries were \$596 million which included \$510 million from APS, \$50 million from SunCor, and \$36 million from El Dorado.

Our long-term debt at December 31, 2000 was \$238 million compared to \$106 million at December 31, 1999. We have a \$250 million line of credit, under which we had \$188 million of borrowings outstanding at December 31, 2000. Our debt repayment requirements for the next three years are approximately: \$213 million in 2001, zero in 2002, and \$25 million in 2003.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. APS pays for its capital requirements with cash from operations and, to the extent necessary, external financing.

During the period from 1998 through 2000, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2001 through 2003, as well.

See the table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. In general, most of APS' projected capital expenditures are for:

- expanding transmission and distribution capabilities to serve growing customer needs;
- upgrading existing utility property; and
- environmental purposes.

During 2000, APS redeemed approximately \$357 million of long-term debt, including premiums, with cash from operations and from the issuance of long- and short-term debt. APS' long-term debt redemption requirements for the next three years are approximately: \$380 million in 2001; \$125

million in 2002; and zero in 2003. APS made optional redemptions of about \$13 million of long-term debt in February 2001. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2000, APS had credit commitments from various banks totaling about \$250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 2000, APS had about \$82 million of commercial paper and no long-term bank borrowings outstanding.

APS' long-term debt was \$2.1 billion at December 31, 2000 and 1999.

Although provisions in APS' first mortgage bond indenture and ACC financing orders establish maximum amounts of additional first mortgage bonds that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Pinnacle West Energy

Pinnacle West Energy has announced plans to build up to 2,800 megawatts (MW) of generating capacity from 2001-2006 at an estimated cost of about \$1.3 billion.

Site	MW
West Phoenix 4	120
West Phoenix 5	530
Redhawk 1	530
Redhawk 2	530
Redhawk 3	530
Redhawk 4	530
TOTAL	2,770

As discussed in greater detail below, Pinnacle West Energy has also announced plans to purchase Nevada Power Company's (NPC) Harry Allen Power Station and SCE's interest in the Palo Verde Nuclear Generating Station (Palo Verde).

Pinnacle West Energy is also considering additional expansion, which may result in additional expenditures.

Pinnacle West Energy expects to fund its capital requirements through internally generated cash, debt issued directly by Pinnacle West Energy, and capital infusions from the parent company's internally generated cash and external financing.

Pinnacle West Energy is currently planning a 650 MW expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units, near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW West Phoenix Unit 5

in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is currently scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately \$65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including the Federal Energy Regulatory Commission (FERC) and the Nevada Public Utility Commission (NPUC). The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada recently requested that the NPUC reexamine NPC's divestiture of generation assets. The timing and result of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original \$300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for \$250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APS Energy Services funded its cash requirements with cash infusions from the parent company.

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the Capital Expenditures Table above for

actual capital expenditures in 2000 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements from internally generated cash and external financings.

As of December 31, 2000, SunCor had a \$120 million line of credit, under which \$110 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2001; \$37 million in 2002; and \$74 million in 2003.

El Dorado does not have any capital requirements over the next three years. El Dorado intends to focus on the realization of the value of its existing investments. El Dorado's future investments are expected to be limited to opportunities related to the energy sector.

APS Energy Services' capital expenditures and other cash requirements will be funded from cash invested by the parent company.

ACCOUNTING MATTERS

We adopted a new standard on accounting for derivatives in 2001. As a result, in January 2001 we recognized a \$3 million after-tax loss in net income as a cumulative effect of a change in accounting principles and a \$64 million after-tax gain reflected in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges. There are still several unresolved issues related to the application of certain provisions of this new standard as it relates to the electric utility industry. The ultimate resolution of these issues by the Financial Accounting Standards Board (FASB) could result in a material impact to our financial statements and increased volatility in future net income and comprehensive income. See Note 2 for further information. Also, see Note 2 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements. As a result of the 1999 Settlement Agreement (see "Regulatory Agreements" above and Note 3), we discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance (\$140 million after income taxes) as an extraordinary charge on the 1999 income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

BUSINESS OUTLOOK

This section describes several major factors affecting our financial outlook.

Competition and Industry Restructuring

Electric Competition (Wholesale)

The National Energy Policy Act of 1992 (1992 Energy Act) and the FERC's subsequent rulemaking activities have established the regulatory framework to open the wholesale electricity market to competition. The 1992 Energy Act amended provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to a competitive wholesale market. The 1992 Energy Act permits utilities to participate in the development of independent electric generating plants for electricity sales to wholesale customers, and also permits the FERC to order transmission access for third parties to transmission facilities owned by another entity. The 1992 Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers. Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including us, with opportunities to sell and deliver electricity at market-based prices.

Electric Competition (Retail)

On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona (the Rules). Among other things, the Rules require most utilities, including APS, to transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. The Rules require the transfer to take place by January 1, 2001, absent a waiver. APS received a waiver in the 1999 Settlement Agreement to allow the transfer of its competitive generation assets and services to affiliates no later than December 31, 2002. Accordingly, we plan to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard offer customers under rates that have been approved by the ACC. These rates are fixed until July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last year, have been volatile. At various times prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects these market conditions to continue in 2001. We believe we have adequately supplemented our current generation portfolio with power purchased through contracts and hedging

techniques that limit exposure to the volatile spot wholesale power market. However, in the event of shortfalls due to unforeseen increases in load demand or generation outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

As discussed in Note 3, the 1999 Settlement Agreement authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. APS intends to move its generation assets to Pinnacle West Energy within that timeframe. Following its receipt of these generation assets, Pinnacle West Energy expects to sell its power at wholesale to our power marketing division (Power Marketing). Power Marketing, in turn, is expected to sell power to APS and to non-affiliated power purchasers. APS is expected to meet fifty percent of its energy needs under a power purchase agreement with Power Marketing. As required by the Rules, APS will acquire the remaining fifty percent of its energy needs through a competitive bid process in which Power Marketing may participate. We believe that these arrangements will allow us to manage APS' exposure to the wholesale power market during the period within which APS' rates are fixed, as discussed in the preceding paragraph.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. Several rural electric cooperatives and the Arizona Consumers Council, a private non-profit public interest group (represented by the Arizona Center for Law in the Public Interest, also a private non-profit public interest organization) have filed court challenges to the Rules. Although these actions do not directly challenge the divestiture provisions of the Rules, they do raise fundamental constitutional issues concerning the ability of the ACC to permit the forces of competition to determine retail electric prices.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement.

The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review.

On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

Neither party challenging the 1999 Settlement Agreement has raised issues regarding the 1999 Settlement Agreement that could not be remedied by the ACC if the Arizona Court of Appeals remands the 1999 Settlement Agreement to the ACC. However, it is impossible to predict with certainty exactly what the ACC would do in the event the order approving the 1999 Settlement Agreement were invalidated, either in whole or in part. Even aside from the pending litigation, the ACC retains continuing jurisdiction over all orders issued by it and can attempt to "rescind, alter or amend" such order under appropriate circumstances and upon notice and hearing.

In May 1998, a law was enacted by the Arizona legislature to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for additional information about the Rules, the 1999 Settlement Agreement, the ongoing litigation related to each, and for legislative developments.

As a result of the foregoing matters, as well as energy market developments, particularly in California (see "California Energy Market Issues" below), electric utility restructuring is in a state of flux in the western United States and around the country.

Generation Expansion

See "Capital Needs and Resources – Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

California Energy Market Issues

SCE and PG&E Corp. (PG&E) have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the California Power Exchange (PX) and California Independent System Operator (ISO).

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon the financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Capital Resources and Cash Requirements – Pinnacle West Energy" above for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Factors Affecting Operating Revenues

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona, and from competitive retail and wholesale bulk power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged 3.8% a year for the three years 1998 through 2000; we currently expect customer growth to average 3.5% to 4% a year for 2001 through 2003. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 4.5% a year in 2001 through 2003, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard offer customers that will switch to unbundled service.

Wholesale activities will be affected by electricity prices and costs of available fuel and purchased power in the western United States, as well as competitive market conditions and regulatory and legislative changes in various state and federal jurisdictions. These factors have significantly affected our wholesale power activities and their resultant earnings contributions over the last several years. We cannot predict future contributions from wholesale activities.

Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply. Such activities are currently not material to our consolidated financial results.

Other Factors Affecting Future Financial Results

Fuel and purchased power costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, our power plant performance, prevailing market prices, and our hedging program for managing such costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, inflation, and other factors.

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 1 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement. Also, see Note 1 regarding current depreciation rates.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally generated cash flow.

The annual earnings contribution from our real estate subsidiary, SunCor, is expected to remain modest over the next several years. SunCor's earnings were \$5 million (excluding the effects of a \$40 million deferred tax asset transfer) in 1998, \$6 million in 1999, and \$11 million in 2000.

El Dorado, our investment subsidiary, is affected by market conditions related to its investments. See Note 1 for a discussion of recent events affecting El Dorado's financial results and its outlook. Historical results are not necessarily indicative of future performance for El Dorado. El Dorado's

strategies focus on realization of the value of its existing investments. Any future investments are expected to be in the energy business.

Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

MARKET RISKS

Our operations include managing market risks related to changes in interest rates, commodity prices, and investments held by the nuclear decommissioning trust fund.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 13). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31,

2000 and December 31, 1999. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2000 and December 31, 1999.

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 2000

(dollars in thousands)	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2001	6.64%	\$ 82,775	7.23%	\$ 438,203	6.63%	\$ 25,266
2002	—	—	8.62%	36,890	8.13%	125,000
2003	—	—	8.61%	73,578	6.89%	25,443
2004	—	—	8.87%	268	6.17%	205,000
2005	—	—	8.89%	294	7.28%	400,000
Years thereafter	—	—	4.13%	483,790	7.47%	610,813
Total		\$ 82,775		\$ 1,033,023		\$ 1,391,522
Fair Value		\$ 82,775		\$ 1,033,023		\$ 1,422,014

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1999

(dollars in thousands)	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2000	5.33%	\$ 38,300	10.25%	\$ 87	5.79%	\$ 114,711
2001	—	—	7.00%	336,117	6.70%	27,488
2002	—	—	8.47%	64,085	8.13%	125,000
2003	—	—	5.51%	50,118	6.87%	25,000
2004	—	—	10.25%	130	6.17%	205,000
Years thereafter	—	—	3.19%	479,727	7.87%	900,483
Total		\$ 38,300		\$ 930,264		\$ 1,397,682
Fair Value		\$ 38,300		\$ 930,264		\$ 1,366,968

Commodity Price Risk

Pinnacle West's Energy Risk Management Committee (the ERMC) has established risk management guidelines to monitor and manage commodity price risks. The ERMC is chaired by Pinnacle West's Vice President of Finance and is comprised of senior executives.

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements. In accordance with Emerging Issues Task Force (EITF) 98-10, "Accounting for contracts involved in energy trading and risk management activities," such trading positions are marked to market. These trading activities are part of our wholesale activities and are reflected in the wholesale revenues and expenses.

As of December 31, 2000, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would have decreased the fair market value of these contracts by approximately \$29 million compared to a \$6 million decrease that would have been realized as of December 31, 1999. The increase in this exposure over 1999 is a result of the increased volume of hedge positions and increased prices in this portfolio. This analysis does not include the favorable impact this same hypothetical price move would have had on certain underlying physical exposures being hedged with the commodity derivative portfolio.

We are exposed to losses in the event of non-performance or non-payment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regional economic and market conditions, including the California energy situation, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the stock market (particularly the technology sector in which El Dorado is currently invested) and the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

REPORT OF MANAGEMENT AND INDEPENDENT AUDITORS' REPORT

REPORT OF MANAGEMENT

The primary responsibility for the integrity of our financial information rests with management, which has prepared the accompanying financial statements and related information. This information was prepared in accordance with generally accepted accounting principles as appropriate in the circumstances, and based on management's best estimates and judgments. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal control. A limiting factor in all systems of internal control is that the cost of the system should not exceed the benefits to be derived. Management believes that our system provides the appropriate balance between such costs and benefits.

Periodically the internal control system is reviewed by both our internal auditors and our independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis. By letter dated February 21, 2001, to the Audit Committee, our independent auditors confirmed that they are independent accountants with respect to us, within the meaning of the Securities Act and the requirements of the Independence Standards Board.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that our systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chairman and
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Phoenix, Arizona

February 9, 2001

CONSOLIDATED STATEMENTS OF INCOME

YEAR ENDED DECEMBER 31,

(dollars in thousands, except per share amounts)

*2000**1999**1998*

	<i>2000</i>	<i>1999</i>	<i>1998</i>
OPERATING REVENUES			
Electric	\$ 3,531,810	\$ 2,293,184	\$ 2,006,398
Real estate	158,365	130,169	124,188
Total	3,690,175	2,423,353	2,130,586
OPERATING EXPENSES			
Fuel and purchased power	1,934,783	796,109	545,297
Operations and maintenance	450,809	446,777	419,433
Real estate operations	134,422	119,516	115,331
Depreciation and amortization (Note 1)	394,410	385,568	379,679
Taxes other than income taxes	99,780	96,606	103,718
Total	3,014,204	1,844,576	1,563,458
OPERATING INCOME	675,971	578,777	567,128
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	—	(1,016)	(9,703)
Net other income and expense	(186)	10,793	609
Total	(186)	9,777	(9,094)
INCOME BEFORE INTEREST AND INCOME TAXES	675,785	588,554	558,034
INTEREST EXPENSE			
Interest charges	171,239	162,381	169,145
Capitalized interest	(21,638)	(11,664)	(18,596)
Total	149,601	150,717	150,549
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	526,184	437,837	407,485
INCOME TAXES (NOTE 4)	223,852	168,065	164,593
INCOME FROM CONTINUING OPERATIONS	302,332	269,772	242,892
Income tax benefit from discontinued operations	—	38,000	—
Extraordinary charge – net of income taxes of \$94,115	—	(139,885)	—
NET INCOME	\$ 302,332	\$ 167,887	\$ 242,892
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,733	84,717	84,774
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	84,935	85,009	85,346
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (NOTE 16)			
Continuing operations – basic	\$ 3.57	\$ 3.18	\$ 2.87
Net income – basic	3.57	1.98	2.87
Continuing operations – diluted	3.56	3.17	2.85
Net income – diluted	3.56	1.97	2.85
DIVIDENDS DECLARED PER SHARE	\$ 1.425	\$ 1.325	\$ 1.225

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

(dollars in thousands)

*2000**1999*

	<i>2000</i>	<i>1999</i>
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 10,363	\$ 20,705
Customer and other receivables – net	513,822	244,599
Accrued utility revenues	74,566	72,919
Materials and supplies (at average cost)	71,966	69,977
Fossil fuel (at average cost)	19,405	21,869
Deferred income taxes (Note 4)	5,793	8,163
Other current assets	97,998	60,562
Total current assets	793,913	498,794
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	371,323	344,293
Other assets (Note 13)	318,249	267,458
Total investments and other assets	689,572	611,751
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,809,566	7,546,314
Less accumulated depreciation and amortization	3,188,302	3,026,194
Total	4,621,264	4,520,120
Construction work in progress	464,540	209,281
Nuclear fuel, net of amortization of \$61,256 and \$66,357	47,389	49,114
Net utility plant	5,133,193	4,778,515
DEFERRED DEBITS		
Regulatory assets (Notes 3 and 4)	469,867	613,729
Other deferred debits	62,606	105,717
Total deferred debits	532,473	719,446
TOTAL ASSETS	\$ 7,149,151	\$ 6,608,506

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

(dollars in thousands)

*2000**1999*

	<i>2000</i>	<i>1999</i>
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 375,805	\$ 186,524
Accrued taxes	89,246	70,510
Accrued interest	42,954	33,253
Short-term borrowings (Note 5)	82,775	38,300
Current maturities of long-term debt (Note 6)	463,469	114,798
Customer deposits	26,189	26,098
Other current liabilities	110,860	26,007
Total current liabilities	1,191,298	495,490
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	1,955,083	2,206,052
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,143,040	1,183,855
Unamortized gain - (Note 10)	68,636	73,212
Other	408,380	444,164
Total deferred credits and other	1,620,056	1,701,231
COMMITMENTS AND CONTINGENCIES (NOTES 3, 12 AND 13)		
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 2000 and 1999	1,532,831	1,537,449
Retained earnings	849,883	668,284
Total common stock equity	2,382,714	2,205,733
TOTAL LIABILITIES AND EQUITY	\$ 7,149,151	\$ 6,608,506

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31,

(dollars in thousands)	<i>2000</i>	<i>1999</i>	<i>1998</i>
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	\$ 302,332	\$ 269,772	\$ 242,892
Items not requiring cash			
Depreciation and amortization	394,410	385,568	379,679
Nuclear fuel amortization	30,083	31,371	32,856
Deferred income taxes – net	(8,973)	(17,413)	41,262
Deferred investment tax credit	740	(23,514)	(23,516)
Other – net	478	(12,476)	1,190
Changes in current assets and liabilities			
Customer and other receivables – net	(269,223)	(10,723)	(50,369)
Accrued utility revenues	(1,647)	(5,179)	(9,181)
Materials, supplies and fossil fuel	475	(8,794)	(2,797)
Other current assets	(37,436)	(12,968)	(6,186)
Accounts payable	193,502	28,193	34,386
Accrued taxes	18,736	12,591	(22,090)
Accrued interest	9,701	1,387	(1,108)
Other current liabilities	89,714	15,047	(5,235)
(Increase) decrease in land held	(25,937)	(12,542)	33,405
Other – net	2,605	(4,720)	(39,350)
Net Cash Flow Provided By Operating Activities	699,560	635,600	605,838
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(658,608)	(343,448)	(319,142)
Capitalized interest	(21,638)	(11,664)	(18,596)
Other – net	(41,761)	(16,143)	(2,144)
Net Cash Flow Used For Investing Activities	(722,007)	(371,255)	(339,882)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	651,000	607,791	148,229
Short-term borrowings – net	44,475	(140,530)	48,080
Dividends paid on common stock	(120,733)	(112,311)	(103,849)
Repayment of long-term debt	(558,019)	(510,693)	(286,314)
Redemption of preferred stock	—	(96,499)	(75,517)
Other – net	(4,618)	(11,936)	(3,531)
Net Cash Flow Provided By (Used For) Financing Activities	12,105	(264,178)	(272,902)
NET CASH FLOW	(10,342)	167	(6,946)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	20,705	20,538	27,484
CASH AND CASH EQUIVALENTS AT END OF YEAR	\$ 10,363	\$ 20,705	\$ 20,538

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEAR ENDED DECEMBER 31,

(dollars in thousands)	<i>2000</i>	<i>1999</i>	<i>1998</i>
Retained earnings at beginning of year	\$ 668,284	\$ 612,708	\$ 473,665
Net income	302,332	167,887	242,892
Common stock dividends	(120,733)	(112,311)	(103,849)
Retained earnings at end of year	\$ 849,883	\$ 668,284	\$ 612,708

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor, and El Dorado. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS, our major subsidiary and Arizona's largest electric utility, provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our unregulated generation operations. APS Energy Services was formed in 1998 and sells energy and energy-related products and services in competitive retail markets in the western United States. SunCor is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. El Dorado is primarily a venture capital and investment firm.

Accounting Records

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements.

During 1997, the EITF of the FASB issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 3 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed \$234 million pre-tax (\$183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction (\$140 million after income taxes) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

1999	2000	2001	2002	2003	1/1-6/30 2004	Total
\$164	\$158	\$145	\$115	\$86	\$18	\$686

The majority of our remaining regulatory assets relate to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note).

The balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (for additional generation information see Note 18):

DECEMBER 31,		
(dollars in thousands)	<i>2000</i>	<i>1999</i>
Electric plant in service and held for future use	\$ 3,856,600	\$ 3,817,919
Accumulated depreciation and amortization	(1,693,079)	(1,664,782)
Construction work in progress	304,992	87,819
Nuclear fuel, net of amortization	47,389	49,114

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a proposed accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis. For the years 1998 through 2000 the rates, as prescribed by our regulators, ranged from a low of 3.33% to a high of 20%. The weighted-average rate was 3.40% for 2000, 3.34% for 1999, and 3.32% for 1998. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. The partnership adjusts the value of its investments at the end of each fiscal quarter. The value of El Dorado's investment in the partnership is determined by various factors beyond our control, including equity market conditions. Most of the partnership's investments are in technology-related companies whose share prices are highly volatile.

Prior to June 2000, we recorded our share of the earnings from the partnership, as the partnership adjusted the value of its investment, on a one-quarter lag. This procedure was followed due to time constraints in obtaining and analyzing such results for inclusion in our consolidated financial statements on a current basis. In the second quarter of 2000, we requested a distribution of our share of the investments held by the

partnership, and we adjusted our investment to reflect the current market value.

An amendment to the partnership agreement resulted in El Dorado receiving a distribution, subject to certain sales restrictions, of securities representing substantially all of El Dorado's investment in the partnership. We began accounting for the securities as available for sale with changes in fair value recorded in other comprehensive income. Gains and losses from the ultimate sale of such securities will be reflected in our net earnings.

The book value of El Dorado's investment in the partnership was approximately \$7 million at December 31, 2000 and \$21 million at December 31, 1999.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plants. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 6.62% for 2000, 6.65% for 1999, and 6.88% for 1998.

Revenues

We record electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method that is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units that it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units that it produces within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS \$0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal and Note 13 for information on nuclear decommissioning costs.

Income Taxes

We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to the parent company.

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Derivative Instruments

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERM, we engage in trading activities intended to profit from market price movements.

Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in revenue or fuel and purchased power expense as an offset to the related item being hedged when the underlying hedged physical transaction closes (deferral method).

Net gains and losses on derivatives utilized for trading are recognized in wholesale revenues on a current basis (the mark to market method). Trading positions are measured at fair value as of the balance sheet date. The net gain was \$9 million for 2000 and \$1 million for 1999.

Statements of Cash Flows

We consider temporary cash investments and marketable securities, with original maturities of less than 90 days, to be cash equivalents for purposes of reporting cash flows. During 2000, 1999, and 1998, we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

	YEARS ENDED DECEMBER 31,		
(dollars in millions)	2000	1999	1998
Interest paid	\$ 132	\$ 141	\$ 144
Income taxes paid	219	200	165
Dividends paid on preferred stock of APS	—	1	10

2. ACCOUNTING MATTERS

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholder's equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

As a result of adopting SFAS No. 133, we recognized \$118 million of derivative assets and \$16 million of derivative liabilities in our balance sheet as of January 1, 2001. We recorded a \$3 million after-tax loss in net income as a cumulative effect of change in accounting principles and a \$64 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges.

In December 2000, the FASB's Derivatives Implementation Group (DIG) discussed whether contracts in the electric industry that have some of the characteristics of purchased and written options should qualify for the "normal purchases and sales" scope exception. The DIG did not reach a conclusion on this issue. We account for electricity contracts with characteristics of options as normal purchases and sales if it is probable that the contract will not be settled in cash and will result in the physical delivery of electricity. The DIG also discussed but did not determine whether electricity contracts subject to "bookout" should qualify for the normal exception. A bookout occurs when one party appears more than once in a contract path for the sale and purchase of energy. In that instance, the counterparties may agree that they will not schedule or deliver physical energy that originates and ends with the same counterparty, but rather will settle in cash the amounts due to or from each counterparty. We account for our non-trading electricity transactions that bookout as gross settlement with physical delivery (and eligible for the normal scope exception) if title transfers, gross cash payment is made, and the transaction retains both performance and credit risk. Trading contracts are measured at fair value (mark to market) as discussed in Note 1.

Our accounting is reflective of the non-storability of our product and the lack of predictability of the demand for electricity at any point in time. If the FASB or DIG ultimately provides us with contrary guidance, we may be required to mark our non-trading electricity contracts to their fair market values each reporting period, which could have a material impact on our financial statements and add significant net income and comprehensive income volatility that would not be reflective of the nature of our business. If these agreements are required to be treated as derivative instruments, a cumulative effect of a change in accounting principles would be applied in the quarter following final resolution of the issues.

In 1999 we adopted EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. The effects of adopting EITF 98-10 were not material to our 1999 financial statements.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB issued a revised exposure draft in February 2000 and we are evaluating the impacts.

3. REGULATORY MATTERS

Electric Industry Restructuring State

1999 SETTLEMENT AGREEMENT. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

The following are the major provisions of the 1999 Settlement Agreement, as approved:

- APS has reduced, and will reduce, rates for standard offer service for customers with loads less than three MW in a

series of annual retail electric price reductions of 1.5% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately \$24 million (\$14 million after income taxes) included the July 1, 1999 retail price decrease of approximately \$11 million (\$7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the 1999 Settlement Agreement, there was a retail price decrease of approximately \$28 million (\$17 million after taxes), or 1.5%, effective July 1, 2000. For customers having loads three MW or greater, standard offer rates will be reduced in varying annual increments that total 5% in the years 1999 through 2002.

- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There will be a moratorium on retail price changes for standard offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition rules, system benefits costs in excess of the levels included in current rates, and costs associated with the "provider of last resort" and standard offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the electric competition rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after

mitigation and exclusive of regulatory assets, are at least \$533 million net present value. APS will not be allowed to recover \$183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover \$350 million net present value through a competitive transition charge (CTC) that will remain in effect through December 31, 2004, at which time it will terminate. Any over/under-recovery due to sales volume variances will be credited/debited against the costs subject to recovery under the adjustment clause described above.

- APS will form a separate corporate affiliate or affiliates and transfer to such affiliate(s) its generating assets and competitive services at book value as of the date of transfer, which transfer shall take place no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.
- When the 1999 Settlement Agreement approved by the ACC is no longer subject to judicial review, APS will move to dismiss all of its litigation pending against the ACC as of the date APS entered into the 1999 Settlement Agreement. To protect its rights, APS has several lawsuits pending on ACC orders relating to stranded cost recovery and the adoption and amendment of the ACC's electric competition rules, which would be voluntarily dismissed at the appropriate time under this provision.

As discussed in Note 1 above, we have discontinued the application of SFAS No. 71 for our generation operations.

RETAIL ELECTRIC COMPETITION RULES. On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona. Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. On December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery, the adoption or amendment of the Rules, and the certification of competitive electric service providers.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification.

The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review. The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access was available to all APS retail customers.
- Electric service providers that get Certificates of Convenience and Necessity from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for non-competitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its generation and other competitive assets and services to affiliates no later than December 31, 2002. See "1999 Settlement Agreement" above for a discussion of the planned timing of the transfer.

1996 REGULATORY AGREEMENT. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows:

(dollars in millions)

Annual Electric Revenue Decrease	Percentage Decrease	Effective Date
\$49	3.4%	July 1, 1996
\$18	1.2%	July 1, 1997
\$17	1.1%	July 1, 1998
\$11	0.7%	July 1, 1999(a)

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse \$200 million of common equity into APS in annual payments of \$50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

LEGISLATION. In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;
- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and
- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one MW

(and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

General

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position it to compete in the new regulatory environment.

Federal

The 1992 Energy Act and recent rulemakings by FERC have promoted increased competition in the wholesale energy markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills will undoubtedly be introduced during the current congressional session. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2001 and beyond. These bills and other bills are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any comprehensive restructuring of the electric utility industry can occur.

4. INCOME TAXES

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset related to income taxes on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS

amortizes this amount as the differences reverse. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate its amortization of the regulatory asset for income taxes over an eight-year period that will end June 30, 2004 (see Note 1). We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income. The components of income tax expense for continuing operations are:

YEAR ENDED DECEMBER 31,

(dollars in thousands)	<i>2000</i>	<i>1999</i>	<i>1998</i>
Current			
Federal	\$ 189,779	\$ 171,491	\$ 105,922
State	42,306	37,501	40,621
Total current	232,085	208,992	146,543
Deferred	(8,973)	(17,413)	41,566
ITC amortization	740	(23,514)	(23,516)
Total expense	\$ 223,852	\$ 168,065	\$ 164,593

The following chart compares pretax income at the 35% federal income tax rate to income tax expense:

(dollars in thousands)	YEAR ENDED DECEMBER 31,		
	2000	1999	1998
Federal income tax expense at 35% statutory rate	\$ 184,164	\$ 153,243	\$ 142,620
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	12,328	14,575	17,848
Preferred stock dividends of APS	—	356	3,396
ITC amortization	740	(23,514)	(23,516)
State income tax net of federal income tax benefit	23,555	23,030	22,764
Other	3,065	375	1,481
Income tax expense	\$ 223,852	\$ 168,065	\$ 164,593

The components of the net deferred income tax liability were as follows:

(dollars in thousands)	YEAR ENDED DECEMBER 31,	
	2000	1999
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	\$ 27,056	\$ 29,446
Other	89,416	133,748
Total deferred tax assets	116,472	163,194
DEFERRED TAX LIABILITIES		
Plant-related	1,081,637	1,104,769
Regulatory asset for income taxes	172,082	234,117
Total deferred tax liabilities	1,253,719	1,338,886
Accumulated deferred income taxes – net	\$ 1,137,247	\$ 1,175,692

Investment Tax Credit

Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our ITCs over a five-year period (1995-1999).

Income Tax Benefit From Discontinued Operations

In 1999, the income tax benefit from discontinued operations for \$38 million resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

5. LINES OF CREDIT

APS had committed lines of credit with various banks of \$250 million at December 31, 2000 and \$350 million at December 31, 1999, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 2000 and 1999 for these lines of credit ranged from 0.09% to 0.125% per annum. APS had no long-term bank borrowings at December 31, 2000 and \$50 million outstanding at December 31, 1999.

APS' commercial paper borrowings outstanding were \$82 million at December 31, 2000 and \$38 million at December 31, 1999. The weighted average interest rate on commercial paper borrowings was 6.64% for the year ended December 31, 2000 and 5.33% for the year ended December 31, 1999.

By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had a revolving line of credit of \$250 million at December 31, 2000 and 1999. The commitment fees were 0.15% in 2000 and 0.10% in 1999. Outstanding amounts at December 31, 2000 were \$188 million and at December 31, 1999 were \$56 million.

SunCor had revolving lines of credit totalling \$120 million at December 31, 2000 and \$100 million at December 31, 1999. The commitment fees were 0.125% in 2000 and 1999. SunCor had \$110 million outstanding at December 31, 2000 and \$94 million outstanding at December 31, 1999.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plants; APS also has unsecured debt; SunCor's debt is collateralized by interests in

certain real property; Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt outstanding at December 31, 2000 and December 31, 1999:

		YEAR ENDED DECEMBER 31,		
(dollars in thousands)	Maturity Dates (a)	Interest Rates	<i>2000</i>	<i>1999</i>
APS				
First mortgage bonds	2000	5.75%	\$ —	\$ 100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	80,000
	2020	10.25%	—	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	70,650
	2024	8.75%	121,668	121,668
	2025	8%	33,075	47,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,993)	(5,860)
Pollution control bonds	2024-2034	Adjustable rate(b)	476,860	476,860
Funds held in trust account for certain pollution control bonds			—	(1,236)
Collateralized loan	2000	5.375%-6.125%	—	10,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	—
Floating rate notes	2001	Adjustable rate(c)	250,000	250,000
Senior notes (d)	2006	6.75%	83,695	83,695
Debentures	2025	10%	—	75,000
Bank loans	2003	Adjustable rate(e)	—	50,000
Capitalized lease obligation	2000	7.48%(f)	—	7,199
Capitalized lease obligation	2001-2003	7.75%	709	—
			2,057,174	2,112,111
SUNCOR				
Revolving credit	2002-2003	(g)	110,000	94,000
Notes payable	2001-2006	(h)	8,163	3,404
Bonds payable	2039	5.85%	5,215	5,335
			123,378	102,739
PINNACLE WEST				
Revolving credit	2001	(i)	188,000	56,000
Senior notes	2001-2003	(j)	50,000	50,000
			238,000	106,000
Total long-term debt			2,418,552	2,320,850
Less current maturities			463,469	114,798
Total long-term debt less current maturities			\$1,955,083	\$2,206,052

- (a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
- (b) The weighted-average rate for the year ended December 31, 2000 was 4.06% and for December 31, 1999 was 3.15%. Changes in short-term interest rates would affect the costs associated with this debt.
- (c) The weighted-average rate for the year ended December 31, 2000 was 7.33% and for December 31, 1999 was 6.8525%.
- (d) APS currently has outstanding \$84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. APS' payments of principal, premium, and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.
- (e) The weighted-average rate for the year ended December 31, 2000 was 6.53% and for December 31, 1999 was 5.5%. Changes in short-term interest rates would affect the costs associated with this debt. At December 31, 2000, we had no long-term bank borrowings outstanding.
- (f) Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined

- cycle plant that was sold and leased back. The capital lease was paid off early and the related asset was purchased in December 2000 (See Note 10).
- (g) The weighted-average rate at December 31, 2000 was 8.61% and at December 31, 1999 was 8.51%. Interest for 2000 and 1999 was based on LIBOR plus 2% or prime plus 0.5%.
- (h) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
- (i) The weighted-average rate at December 31, 2000 was 7.51% and at December 31, 1999 was 6.825%. Interest for 2000 was based on LIBOR plus 0.75% and interest for 1999 was based on LIBOR plus 0.33%.
- (j) Includes two series of notes: \$25 million at 6.62% due 2001, and \$25 million at 6.87% due 2003.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2005:

- \$463 million in 2001;
- \$162 million in 2002;
- \$99 million in 2003;
- \$205 million in 2004; and
- \$400 million in 2005.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment. The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2000.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock. Preferred stock balances of APS at December 31, 2000 and

1999 were zero. Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 2000 are as follows:

(dollars in thousands)	Number of Shares	Par Value Amount
Balance, December 31, 1997	291,098	\$ 29,110
Retirements		
\$10.00 Series U	(197,087)	(19,709)
Balance, December 31, 1998	94,011	9,401
Retirements		
\$10.00 Series U	(94,011)	(9,401)
Balance, December 31, 1999	—	—
Balance, December 31, 2000	—	\$ —

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 2000 is as follows:

(dollars in thousands)	Number of Shares	Amount
Balance, December 31, 1997	84,824,947	\$ 1,553,771
Common stock expense	—	(3,128)(a)
Balance, December 31, 1998	84,824,947	1,550,643
Common stock expense	—	(13,194)(a)
Balance, December 31, 1999	84,824,947	1,537,449
Common stock expense	—	(4,618)
Balance, December 31, 2000	84,824,947	\$ 1,532,831

(a) Including premiums and expenses of preferred stock issues of APS.

9. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plans

Through 1999, Pinnacle West and its subsidiaries each sponsored defined benefit pension plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single pension plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under these plans based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount

required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 2000 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- \$2 million in 2000;
- \$4 million in 1999; and
- \$11 million in 1998.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others:

(dollars in thousands)	<i>2000</i>	<i>1999</i>	<i>1998</i>
Service cost - benefits earned during the period	\$ 24,955	\$ 24,982	\$ 24,817
Interest cost on projected benefit obligation	58,361	52,905	51,524
Expected return on plan assets	(77,231)	(68,335)	(54,513)
Amortization of:			
Transition asset	(3,227)	(3,226)	(3,226)
Prior service cost	2,078	2,078	2,078
Net actuarial gain	(1,633)	—	—
Net periodic pension cost	\$ 3,303	\$ 8,404	\$ 20,680

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the balance sheets:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Funded status – pension plan assets more than (less than) projected benefit obligation	\$ (20,730)	\$ 37,275
Unrecognized net transition asset	(16,781)	(20,008)
Unrecognized prior service cost	18,558	20,636
Unrecognized net actuarial gains	(23,816)	(101,153)
Net pension liability recognized in the balance sheets	\$ (42,769)	\$ (63,250)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Projected pension benefit obligation at beginning of year	\$ 742,638	\$ 731,305
Service cost	24,955	24,982
Interest cost	58,361	52,905
Benefit payments	(30,568)	(29,694)
Actuarial (gains)/losses	540	(36,860)
Projected pension benefit obligation at end of year	\$ 795,926	\$ 742,638

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Fair value of pension plan assets at beginning of year	\$ 779,913	\$ 690,271
Actual return on plan assets	1,851	93,977
Employer contributions	24,000	25,359
Benefit payments	(30,568)	(29,694)
Fair value of pension plan assets at end of year	\$ 775,196	\$ 779,913

We made the assumptions below to calculate the pension liability:

	<i>2000</i>	<i>1999</i>
Discount rate	7.75%	7.75%
Rate of increase in compensation levels	4.25%	4.25%
Expected long-term rate of return on assets	10.00%	10.00%

Employee Savings Plan Benefits

Through 1999, Pinnacle West and its subsidiaries each sponsored defined contribution savings plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single defined contribution savings plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. In a defined contribution plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of approximately \$4 million for 2000, 1999, and 1998.

Postretirement Plans

We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- \$ 3 million for 2000
- \$ 7 million for 1999 and
- \$ 9 million for 1998.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others:

(dollars in thousands)	<i>2000</i>	<i>1999</i>	<i>1998</i>
Service cost - benefits earned during the period	\$ 8,613	\$ 8,939	\$ 7,890
Interest cost on accumulated benefit obligation	19,315	17,366	15,763
Expected return on plan assets	(22,381)	(18,454)	(12,001)
Amortization of:			
Transition obligation	7,698	7,698	7,698
Net actuarial gains	(7,983)	(5,117)	(2,952)
Net periodic postretirement benefit cost	\$ 5,262	\$ 10,432	\$ 16,398

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Funded status – postretirement plan assets more than (less than) projected benefit obligation	\$ (14,851)	\$ 25,549
Unrecognized net obligation at transition	92,446	100,145
Unrecognized net actuarial gains	(81,280)	(128,309)
Net postretirement amount recognized in the balance sheets	\$ (3,685)	\$ (2,615)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Accumulated postretirement benefit obligation at beginning of year	\$ 231,989	\$ 237,679
Service cost	8,613	8,939
Interest cost	19,315	17,366
Benefit payments	(8,905)	(8,761)
Actuarial (gains) losses	12,994	(23,234)
Accumulated postretirement benefit obligation at end of year	\$ 264,006	\$ 231,989

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)	<i>2000</i>	<i>1999</i>
Fair value of postretirement plan assets at beginning of year	\$ 257,538	\$ 213,410
Actual return on plan assets	(4,436)	42,975
Employer contributions	4,958	9,914
Benefit payments	(8,906)	(8,761)
Fair value of postretirement plan assets at end of year	\$ 249,154	\$ 257,538

We made the assumptions below to calculate the postretirement liability:

	<i>2000</i>	<i>1999</i>
Discount rate	7.75%	7.75%
Expected long-term rate of return on assets – after tax	8.77%	8.77%
Initial health care cost trend rate – under age 65	7.00%	7.00%
Initial health care cost trend rate – age 65 and over	6.00%	6.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

The following table shows the effect of a 1% increase or decrease in the health care cost trend rate:

(dollars in millions)	1% increase	1% decrease
Effect on 2000 cost of postretirement benefits other than pensions	\$ 5	\$ (4)
Effect on the accumulated postretirement benefit obligation at December 31, 2000	43	(34)

10. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale lease-back transactions. APS accounts for these leases as operating leases. The gain of approximately \$140 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are approximately \$49 million per year for the years 2001-2015.

In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 2000 was \$33 million.

In December 2000, APS purchased Units 1, 2, and 3 of West Phoenix Power Plant. These units were previously reflected as a capital lease.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Total lease expense was \$58 million in 2000, \$52 million in 1999, and \$55 million in 1998.

Estimated future minimum lease commitments, are approximately \$67 million for each of the years 2001 to 2005 and \$663 million thereafter.

11. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at

December 31, 2000. APS' share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

(dollars in thousands)	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	\$1,824,480	\$ 814,693	\$ 7,414
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	571,573	265,571	29,593
Four Corners Steam Generating Station Units 4 and 5	15.0%	152,717	75,797	—
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	231,509	99,623	4,899
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	73,382	40,023	686
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	67,987	22,813	—
Navajo Southern System	31.4%(b)	27,290	17,804	55
Palo Verde – Yuma 500KV System	23.9%(b)	9,712	3,844	1
Four Corners Switchyards	27.5%(b)	3,071	1,925	—
Phoenix – Mead System	17.1%(b)	36,418	2,681	—
Palo Verde – Estrella 500KV system	50.0%(b)	—	—	610

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

12. COMMITMENTS AND CONTINGENCIES**Litigation**

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Power Service Agreement

APS is a party to a power service agreement with Citizens Communications Company (Citizens) under which APS supplies Citizens with power. By letter dated March 7, 2001, Citizens advised APS that it believes APS has over-charged Citizens by over \$50 million under the agreement since the summer of 2000. APS believes that its charges to Citizens under the agreement are fully in accordance with the terms of the agreement and APS will vigorously defend any contrary claims raised by Citizens.

Palo Verde Nuclear Generating Station

Pursuant to the Nuclear Waste Policy Act of 1982, the DOE must accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The United States Nuclear Regulatory Commission (NRC) requires operators of nuclear power reactors to enter

into spent fuel disposal contracts with the DOE. Under the Nuclear Waste Policy Act of 1982, the DOE was to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998. The DOE has announced that such a permanent repository cannot be completed before 2010, and that it does not intend to begin accepting spent fuel prior to that date.

In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision precluding the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision, a number of utilities filed damages actions against DOE in the court of Federal Claims. In decisions that became final in December 2000, the United States Court of Appeals for the Federal Circuit held that utilities do not have to exhaust the DOE administrative claims before filing lawsuits for damages against the DOE in the court of Federal Claims.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent

fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates that it will incur \$113 million (in 2000 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2000, APS had recorded a liability and regulatory asset of \$40 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of \$200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately \$88 million, subject to an annual limit of \$10 million per incident. Based upon our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately \$77 million, with an annual payment limitation of approximately \$9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of \$2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel And Purchased Power Commitments

APS is a party to various fuel and purchased power contracts with terms expiring from 2001 through 2021 that include required purchase provisions. APS estimates its contract requirements to be approximately \$277 million in 2001; \$145 million in 2002; \$90 million in 2003; \$83 million in 2004; and \$55 million in 2005. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit APS to decrease its required purchases under certain circumstances.

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about \$103 million. The portion of the coal mine reclamation obligation related to coal already burned is about \$58 million at December 31, 2000 and is included in deferred credits-other in the Balance Sheet.

A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 2000 was about \$32 million.

California Energy Market Issues

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Generation Expansion" below for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Construction Program

Consolidated capital expenditures in 2001 are estimated at:

(dollars in millions)	<i>2001</i>
APS	\$ 455
Pinnacle West Energy	659
SunCor	75
Other	21
Total	\$ 1,210

Generation Expansion

Pinnacle West Energy has announced plans to build and acquire up to 2,800 MW of generating capacity from 2001-2006 at an estimated cost of about \$1.3 billion.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW Unit 5 in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately \$65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including FERC and the NPUC. The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada has recently requested that the NPUC reexamine the divestiture of generation. The timing and results of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West

Energy acquires the Four Corners interest at the original \$300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for \$250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded \$11 million for nuclear decommissioning expense in each of the years 2000, 1999, and 1998. APS estimates it will cost about \$1.8 billion (\$493 million in 2000 dollars) to decommission its share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decommissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations. The trust accounts are reported in investments and other assets on the Consolidated Balance Sheets at their market value of \$205 million at December 31, 2000 and \$176 million at December 31, 1999. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

See Note 2 for a proposed accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

14. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2000 and 1999 is as follows:

(dollars in thousands, except per share amounts)

2000

QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	\$ 446,228	\$ 720,174	\$ 1,567,960	\$ 797,448
Real Estate	41,889	36,374	39,396	40,706
Operating Income (a)	\$ 96,271	\$ 201,153	\$ 256,001	\$ 122,546
Net income	\$ 54,070	\$ 89,901	\$ 116,049	\$ 42,312
Earnings per average common share outstanding				
Net income – basic	\$ 0.64	\$ 1.06	\$ 1.37	\$ 0.50
Net income – diluted	\$ 0.64	\$ 1.06	\$ 1.37	\$ 0.50
Dividends declared per share	\$ 0.35	\$ 0.35	\$ 0.35	\$ 0.375

(dollars in thousands, except per share amounts)

1999

QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	\$ 413,983	\$ 511,434	\$ 867,630	\$ 500,137
Real Estate	24,533	32,697	26,640	46,299
Operating Income (a)	\$ 91,599	\$ 148,968	\$ 240,294	\$ 97,916
Income from continuing operations	\$ 30,690	\$ 68,702	\$ 125,579	\$ 44,801
Income tax benefit from discontinued operations	—	—	38,000	—
Extraordinary charge – net of income tax	—	—	(139,885)	—
Net income	\$ 30,690	\$ 68,702	\$ 23,694	\$ 44,801
Earnings (loss) per average common share outstanding				
Continuing operations – basic	\$ 0.36	\$ 0.81	\$ 1.48	\$ 0.53
Discontinued operations – basic	—	—	0.45	—
Extraordinary charge – basic	—	—	(1.65)	—
Net income – basic	\$ 0.36	\$ 0.81	\$ 0.28	\$ 0.53
Continuing operations – diluted	\$ 0.36	\$ 0.81	\$ 1.48	\$ 0.53
Discontinued operations – diluted	—	—	0.45	—
Extraordinary charge – diluted	—	—	(1.65)	—
Net income – diluted	\$ 0.36	\$ 0.81	\$ 0.28	\$ 0.53
Dividends declared per share (b)	\$ 0.325	\$ 0.65	\$ —	\$ 0.35

(a) Electric revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(b) Dividends for the quarter ending September 30, 1999 were declared in June 1999.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2000 and 1999 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2000 and 1999 fair values of such investments, which we determine by using quoted market values, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was \$2.42 billion on December 31, 2000, with an estimated fair value of \$2.48 billion. On December 31, 1999, the carrying value of our long-term debt (excluding a capitalized lease obligation) was \$2.31 billion, with an estimated fair value of \$2.29 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

The following table presents earnings per average common share outstanding (EPS):

	<i>2000</i>	<i>1999</i>	<i>1998</i>
Basic EPS:			
Continuing operations	\$ 3.57	\$ 3.18	\$ 2.87
Discontinued operations	—	0.45	—
Extraordinary charge	—	(1.65)	—
Net income	\$ 3.57	\$ 1.98	\$ 2.87
Diluted EPS:			
Continuing operations	\$ 3.56	\$ 3.17	\$ 2.85
Discontinued operations	—	0.45	—
Extraordinary charge	—	(1.65)	—
Net income	\$ 3.56	\$ 1.97	\$ 2.85

Dilutive stock options increased average common shares outstanding by 202,738 shares in 2000, 291,392 shares in 1999, and 571,728 shares in 1998. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,935,282 shares in 2000, 85,008,527 shares in 1999, and 85,345,946 shares in 1998.

Options to purchase 517,614 shares of common stock were outstanding at December 31, 2000 but were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted EPS were 506,734 at December 31, 1999 and 244,200 at December 31, 1998.

17. STOCK-BASED COMPENSATION

Pinnacle West offers two stock incentive plans for our and our subsidiaries' officers and key employees.

The plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

The awards outstanding under the incentive plans at December 31, 2000 approximate 1,569,171 non-qualified stock options, 193,992 shares of restricted stock, and no incentive stock options, stock appreciation rights or dividend equivalents.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective beginning in 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value of options granted (fair value method). We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

If we had recorded compensation expense based on the fair value method, our net income and earnings per share would have been reduced to the following pro forma amounts:

(dollars in thousands)	<i>2000</i>		<i>1999</i>	<i>1998</i>
Net income				
As reported	\$ 302,332	\$ 167,887	\$ 242,892	
Pro forma (fair value method)	\$ 301,102	\$ 166,913	\$ 242,177	
Earnings per share – basic				
As reported	\$ 3.57	\$ 1.98	\$ 2.87	
Pro forma (fair value method)	\$ 3.55	\$ 1.97	\$ 2.86	

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the

option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	<i>2000</i>	<i>1999</i>	<i>1998</i>
Risk-free interest rate	5.81%	5.68%	4.54%
Dividend yield	3.48%	3.33%	3.03%
Volatility	32.00%	20.50%	18.80%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 2000, 1999, and 1998 and changes during the years ending on those dates:

(dollars in thousands)	2000 Shares	2000 Weighted Average Exercise Price	1999 Shares	1999 Weighted Average Exercise Price	1998 Shares	1998 Weighted Average Exercise Price
Outstanding at beginning of year	1,441,124	\$ 33.45	1,563,512	\$ 27.95	1,554,631	\$ 24.38
Granted	451,450	43.28	458,450	35.95	244,200	46.78
Exercised	(283,819)	20.90	(516,838)	18.19	(217,317)	23.09
Forfeited	(39,584)	39.86	(64,000)	40.36	(18,002)	33.42
Outstanding at end of year	1,569,171	37.55	1,441,124	33.45	1,563,512	27.95
Options exercisable at year-end	831,537	34.37	835,381	29.69	1,106,165	22.04
Weighted average fair value of options granted during the year		11.81		7.05		8.15

The following table summarizes information about our stock option plans at December 31, 2000:

Exercise Prices Per Share	Options Outstanding	Weighted Average Remaining Contract Life (Years)	Options Exercisable
\$10.06	7,000	.50	7,000
15.75	10,000	.90	10,000
17.68	4,900	1.10	4,900
18.13	14,000	1.50	14,000
19.00	58,618	3.90	58,618
19.56	15,000	1.90	15,000
22.13	33,250	3.00	33,250
23.25	14,000	2.50	14,000
27.16	20,000	9.20	5,000
27.44	84,918	4.90	84,918
31.44	87,335	5.90	87,335
34.66	327,113	8.90	118,124
36.56	5,000	8.80	2,083
39.75	170,636	7.00	170,636
41.00	70,000	8.10	44,722
44.03	431,450	9.90	11,985
46.78	215,951	7.90	149,966
\$10.06 – \$46.78	<u>1,569,171</u>		<u>831,537</u>

18. BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment) which consist of the transmission and distribution of electricity and wholesale activities (delivery business segment) and the generation of electricity (generation business segment). The other

amounts include activity relating to the parent company and other subsidiaries including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Financial data for the business segments is provided as follows:

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 2000

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	\$ 990,415	\$ 3,531,810	\$ 158,365	\$ (990,415)	\$ 3,690,175
Operating expense	600,389	2,871,329	138,677	(990,415)	2,619,980
Operating margin	390,026	660,481	19,688	—	1,070,195
Depreciation and amortization	125,220	263,446	5,744	—	394,410
Interest	41,808	96,081	11,712	—	149,601
Pretax margin	222,998	300,954	2,232	—	526,184
Income taxes	87,828	134,692	1,332	—	223,852
Earnings for common stock	\$ 135,170	\$ 166,262	\$ 900	\$ —	\$ 302,332
Total assets	\$ 2,606,046	\$ 4,068,510	\$ 474,595	\$ —	\$ 7,149,151
Capital expenditures	\$ 379,761	\$ 285,455	\$ 49,949	\$ —	\$ 715,165

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1999

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	\$ 853,755	\$ 2,292,798	\$ 130,555	\$ (853,755)	\$ 2,423,353
Operating expense	522,925	1,672,169	106,876	(853,755)	1,448,215
Operating margin	330,830	620,629	23,679	—	975,138
Depreciation and amortization	121,683	260,374	3,511	—	385,568
Interest and preferred stock dividend requirements	40,753	101,855	9,125	—	151,733
Pretax margin	168,394	258,400	11,043	—	437,837
Income taxes	47,976	111,512	8,577	—	168,065
Income tax benefit from discontinued operations – PNW	—	—	38,000	—	38,000
Extraordinary charge – net of income tax of \$94,115	—	(139,885)	—	—	(139,885)
Earnings for common stock	\$ 120,418	\$ 7,003	\$ 40,466	\$ —	\$ 167,887
Total assets	\$ 2,342,291	\$ 3,795,846	\$ 470,369	\$ —	\$ 6,608,506
Capital expenditures	\$ 110,798	\$ 241,469	\$ 126,581	\$ —	\$ 478,848

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1998

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	\$ 858,340	\$ 2,006,398	\$ 124,188	\$ (858,340)	\$ 2,130,586
Operating expense	522,696	1,414,753	104,061	(858,340)	1,183,170
Operating margin	335,644	591,645	20,127	—	947,416
Depreciation and amortization	135,406	241,168	3,105	—	379,679
Interest and preferred stock dividend requirements	37,045	108,670	14,537	—	160,252
Pretax margin	163,193	241,807	2,485	—	407,485
Income taxes	49,969	109,487	5,137	—	164,593
Earnings for common stock	\$ 113,224	\$ 132,320	\$ (2,652)	\$ —	\$ 242,892
Total assets	\$ 2,399,560	\$ 3,993,740	\$ 431,246	\$ —	\$ 6,824,546
Capital expenditures	\$ 85,767	\$ 241,638	\$ 73,133	\$ —	\$ 400,538